Dispatch of unscheduled generation: 23-27 January 2011

Final report

5 April 2011

Market Performance

Executive summary

When the System Operator (SO) requires a generation unit to run to meet security requirements, even though the final price is less than its offer price, the generation unit is said to be constrained-on. The owner of a constrained-on generator is entitled to compensation over and above the final price. Compensation is based on the difference between the offer price and the final price. The funds required to make the payment are collected by invoicing purchasers in the wholesale market (and the SO) in the following month.

Spot market purchasers paid over $7 million for constrained-on generation in January 2011 compared to $1 million - $2 million in a typical month. The large bill for constrained-on generation arose from extensive use of constrained-on arrangements during 23-27 January 2011 and from high prices paid for constrained-on generation, particularly at Huntly, on those days.

The heavy use of constrained-on arrangements in late January occurred due to the System Operator's inability to add new constraints to their Scheduling Pricing and Dispatch (SPD) model to reflect temporary grid arrangements whilst the Whakamaru-Otahuhu 400 kV circuit is being installed. Ironically, the need for the additional constraints in SPD arose from the abundant hydro resources available to Waikato hydro stations in January, leading to large generation volumes from those stations and a consequent requirement for additional generation north of Hamilton to maintain grid security. The SO successfully added the necessary constraint to SPD on 28 January 2011.

A key issue with constraining-on plant is that it provides no opportunity for other parties to offer assistance in resolving the underlying grid security problem. Spot market purchasers, and other generators, don't know in real-time the structure of the offers from the constrained-on generator and therefore they are not given the opportunity to reduce demand or offer additional generation to the SO.

Although discretion to constrain-on plant is a necessary tool for the SO to manage grid security, under current arrangements it can exacerbate situations where there is very weak competitive pressure on the constrained-on generator. The reality in late January was that significant thermal capacity in Auckland was not available to the market because of planned maintenance. This left the Huntly units in a last resort position and voluntary demand reduction as the main opportunity to constrain offer prices. Under current constrained-on arrangements, spot market purchasers didn't have any opportunity to take these actions.

The Electricity Authority (Authority) is currently developing a dispatchable demand regime, which would provide spot market purchasers with the opportunity to be treated in the dispatch process in the same manner as generation. If introduced, this regime has the potential to provide the SO with additional options when facing situations like that encountered in late January.

Nevertheless, the Authority believes there is merit in considering additional measures to better manage constrained-on situations. Possible next steps include consideration of potential Code changes suggested by:

- Examining how better information can be provided to the market in advance of and during periods of unscheduled plant dispatch. For example, further consideration could be given to whether and how the market could be more quickly informed of the offer prices of plant that are constrained-on;
- Examining whether there are market-based solutions to increasing the options available to the SO during constrained-on periods. For example, consideration could be given to whether

it is feasible and cost-effective to establish a constrained-on market analogous to the instantaneous reserves market; and

- Examining the SO's ability to use its automatic constraint builder (SFT) to help reflect the cost of managing system security in pre-dispatch schedules and ultimately final nodal prices.

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1.1 When the System Operator (SO) requires a generation unit to run to meet security requirements, even though the final price is less than its offer price, the generation unit is said to be constrained-on. The owner of a constrained-on generator is entitled to compensation over and above the final price. Compensation is based on the difference between the offer price and the final price. The funds required to make the payment are collected by invoicing purchasers in the wholesale market (and the SO) in the following month.

1.2 The SO required unscheduled plant to be dispatched on several occasions in January 2011. Some of the constrained-on plant had been offered in at relatively high prices. Consequently, purchasers were required to pay over $7 million in February for constrained-on payments incurred in January. Of this total, over $5.9 million was incurred at Huntly in the three days of 25-27 January 2011. Constrained-on costs for all of New Zealand are typically in the range of $1 million – $2 million per month.

1.3 Although discretion to constrain on plant is a necessary tool for the SO to manage grid security, the Electricity Authority (Authority) is concerned that, in this particular case, it may not have been the least-cost tool available.[1] Moreover, even when constraining on is the least-cost option, the costs of running out-of-merit-order plant are not allocated efficiently. Constrained-on costs are borne by all off-take customers on a national pro-rata basis.

1.4 Constrained-on costs are not reflected in market prices. So participants remain unaware of the financial implications of the system-security situation the SO is trying to manage. The absence of cost-reflective prices or real-time notifications of any kind means that participants cannot take action to mitigate the liability they face but are informed about well after the event.

1.5 This report briefly summarises the background to the underlying grid security issue that gave rise to the constrained-on costs in January 2011. The events during 23-27 January 2011 are then described. The key issues are then discussed and the report concludes by suggesting three possible next steps in terms of Code devlopment.

2 Background to relevant grid security issues

2.1 In essence, the underlying grid security issues can be summarised as follows:

a) The Arapuni-Pakuranga 110 kV circuit was removed in August 2010 to make way for the new Whakamaru-Otahuhu 400 kV circuit;

b) This has created grid security issues at times, especially when thermal plant north of Hamilton is out of service;

c) The SO has been managing these issues by splitting the Kinleith bus, but this action constrains the amount of Waikato hydro generation that can be injected onto the grid without increasing generation north of Hamilton;

d) The required balance of generation would normally be identified by adding additional constraints in the Scheduling, Pricing and Dispatch (SPD) model, but that didn't occur until 28 January 2011; and

1 When plant is constrained-on, it may either be constrained to run at a higher load than was scheduled or it may be constrained to run when it wasn't scheduled to run at all.

e) With Waikato hydro stations needing to generate large amounts of electricity to deal with large hydro inflows in late January, the SO had to constrain-on plant at Huntly and Auckland to avoid curtailing demand.

2.2 The rest of this section elaborates on these developments.

2.3 The need to constrain on plant at Huntly and Southdown in the upper North Island during 23-27 January 2011 arose because of problems associated with maintaining security on the 220 kV circuit from Whakamaru to Hamilton (see Figure 1) coupled with the absence of the appropriate constraint equations in the SPD model. Without the appropriate SPD constraints, and under certain generation conditions, managing the potential overloading of the 220 kV Hamilton-Whakamaru (HAM-WKM) circuit becomes complicated due to transmission constraints and other issues on the 110 kV network.[2]

2.4 Figure 1 presents a simplified representation of the relevant section of the network in the Waikato region.[3] It is important to recognise that the 220 kV and 110 kV networks depicted in the figure are connected – not only at Hamilton, as shown in the figure, but also at Otahuhu in the north and in the vicinity of Whakamaru and Tarukenga in the south. The boxes with the dashed lines represent these connections.

2.5 The general northward flow of power is split as it passes through the Waikato – some power flows north through the 110 kV network while most flows north through the 220 kV network. With the exception of Arapuni and Karapiro, which inject into the 110 kV network, the hydro stations along the Waikato River inject into the 220 kV network. Because Kinleith is a substantial point of off-take, power typically flows southward from Arapuni to Kinleith, although the flow is generally northward through the rest of the 110 kV network in the Waikato region.

2.6 One of the 110 kV complexities relates to insufficient transmission capacity between Tarukenga and Hamilton, i.e. between either Arapuni and Hamilton or Kinleith and Tarukenga. This lack of transmission capacity has arisen since the Arapuni-Pakuranga (ARI-PAK) circuit was taken out of service in August 2010 to make way for the Whakamaru-Otahuhu 400 kV circuit, which was approved by the Electricity Commission in July 2007 and is currently under construction. The decommissioning of the ARI-PAK circuit means that the only outlet for generation from Arapuni is either Kinleith or Hamilton.

2.7 When offers of generation north of the Arapuni-Hamilton constraint are inadequate, a greater flow of power through the 220 kV network is required. Under these conditions, there exists a risk that if the 220 kV HAM-WKM circuit were to trip, the 110 kV Kinleith-Tarukenga (KIN-TRK) circuit would overload. The SO has determined that system security can be maintained by splitting open the Kinleith bus, thereby isolating the KIN-TRK circuit from the 110 kV network north of Kinleith.

2.8 When the need to split the Kinleith bus arises, the SO declares a grid emergency, the Grid Owner offers the Kinleith split, and the SO reconfigures the grid by putting in place the Kinleith split. This happens quite frequently, as can be seen in Figure 2.

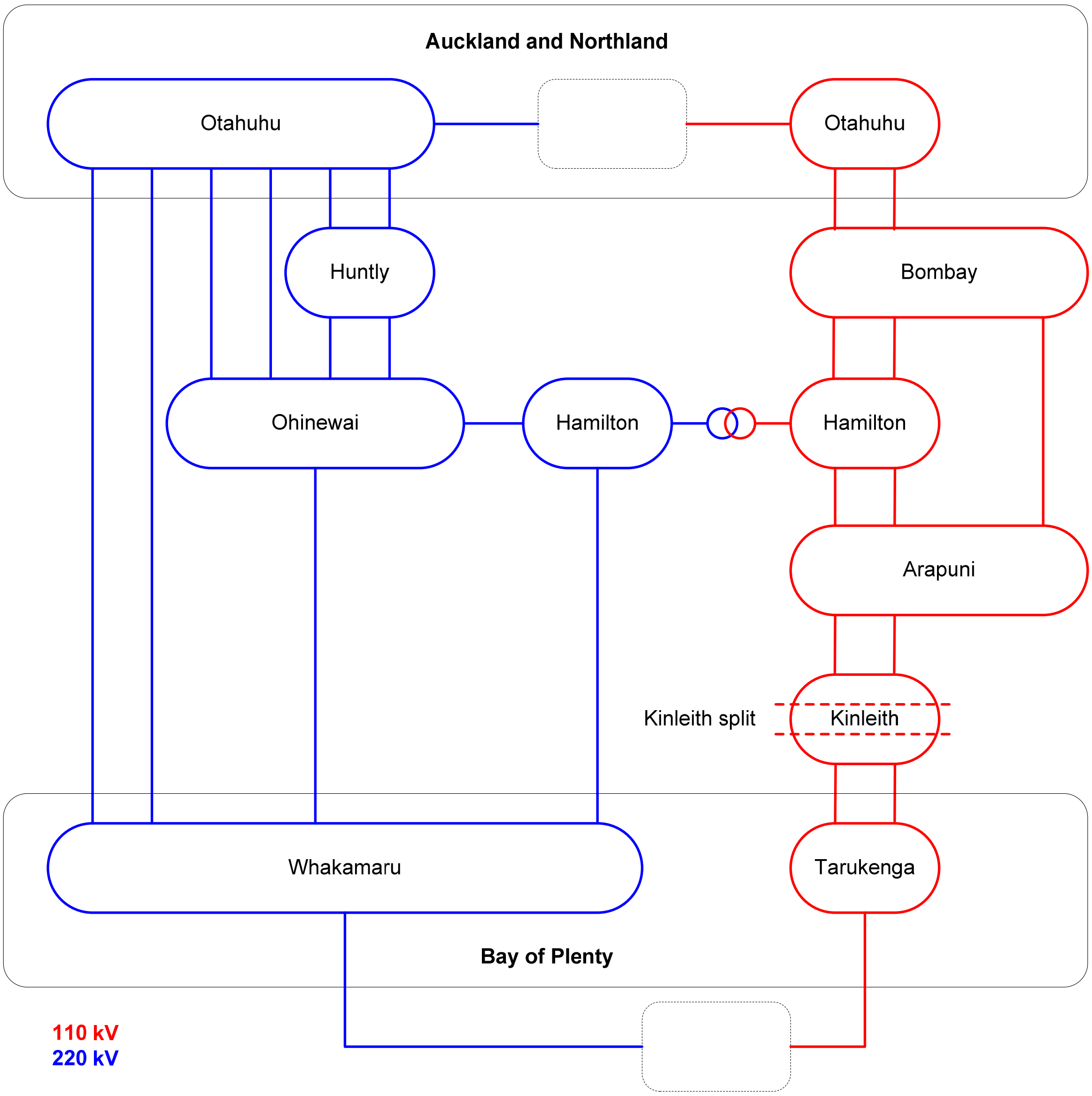
2.9 If thermal plant north of Kinleith is out of service, the usage of the split may increase. Otahuhu B (OTC) was taken out of service on 1 December 2010 for routine maintenance and was returned to service on 28 January 2011. Wholesale prices were at historically very high levels from early December until about 18 December 2010, which resulted in significant generation at Huntly. But

2 The following three documents prepared by the SO provide additional background material: The 11 and 18 February 2011 letters to the Authority at http://www.ea.govt.nz/industry/monitoring/reports-publications/ and the SO report at http://www.systemoperator.co.nz/f1688,45099321/System-operator-discretion-23-27-Jan-2011.pdf.

3 For a detailed line diagram, see http://www.systemoperator.co.nz/f1686,36542743/NIPS6_Aug_10_Web.pdf.

when the wholesale price declined around 19 December 2010 and with OTC out of service, the frequency with which the split was used increased. This is noticeable in Figure 2. In total, the Kinleith split was used on 36 of the 62 days in December 2010 and January 2011.

Figure 1 Stylized line diagram



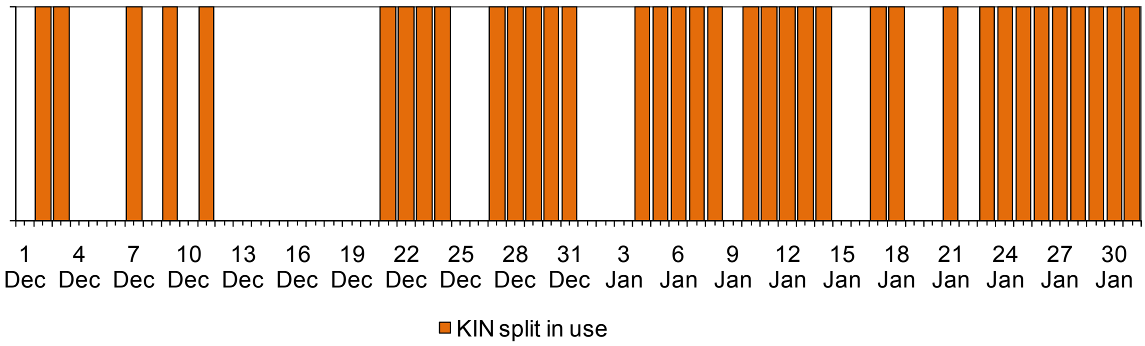
Source: Electricity Authority

2.10 However, under certain generation conditions, the use of the Kinleith split can exacerbate the risk of the 220 kV HAM-WKM circuit overloading in the event of a trip on the 220 kV Ohinewai-Whakamaru (OHW-WKM) circuit. This is because northward flowing power from south of the Waikato region must now all flow through the 220kV network. In situations where the circuits are already heavily loaded, e.g. if there is substantial generation from the Waikato hydro plant, then the transfer of energy to the HAM-WKM circuit following a trip of the OHW-WKM circuit may overload the HAM-WKM circuit.

2.11 Contingent network security is usually managed within SPD through the inclusion of branch group constraints. These constraints are identified, developed, and included within the scheduling, pricing and dispatch process by the SO.[4,5,6] In this instance, the relevant constraint would manage flows through the HAM-WKM circuit for a contingency on the OHW-WKM circuit when the Kinleith split is in place. The advantage of such an outage constraint in SPD is that the cost of managing security is reflected in nodal wholesale prices and market participants are able to observe the price impacts of the constraint in pre-dispatch and real-time pricing schedules. In addition, the need for the SO to instruct out-of-merit order plant to run is reduced.

Figure 2 Frequency of Kinleith split usage

1 December 2010 – 31 January 2011



Source: Electricity Authority

2.12 An alternative option is to require unscheduled generation in the upper North Island to be dispatched. In other words, constrain on plant at Huntly or Auckland, or both. This has the effect of displacing (lower cost) generation elsewhere in the system and reducing the load on the 220 kV network north of Whakamaru. This was what occurred during 23-27 January 2011. One of the issues with this approach is that nodal wholesale prices do not reflect the transmission constraints affecting system dispatch.

3 Summary of events

3.1 Events over the period 23-28 January are briefly summarised. For additional detail, see Appendix A or the letters provided by the SO and Genesis Power Limited (Genesis).[7]

Generation conditions

3.2 Following substantial rainfall in the Waikato catchment area, generation from the Waikato hydro system ramped up on 23 January 2011, increasing by about four GWh per day (Figure 3). Consequently, as can be seen in Figure 3, wholesale prices in the region dropped to less than $20/MWh. This in turn meant that thermal plant at Huntly and Auckland was not being dispatched to any great degree because that plant is unable to be profitably offered at a price as low as the Waikato hydro. Furthermore, as noted above, OTC was out of service for scheduled maintenance.

4 See http://www.systemoperator.co.nz/f1949,3537409/PR-OC-208_Identify_Need_for_Constraints.pdf.

5 See http://www.systemoperator.co.nz/f1949,3537406/PR-OC-204-Security-Constraints-Process-Overview.pdf.

6 One of the SO's procedures outlined in Section 3 of its security constraints process document (see previous footnote) is to manage and assess Grid Owner offers. Hence, the Grid Owner's offer of the Kinleith split should have triggered the constraint identification process.

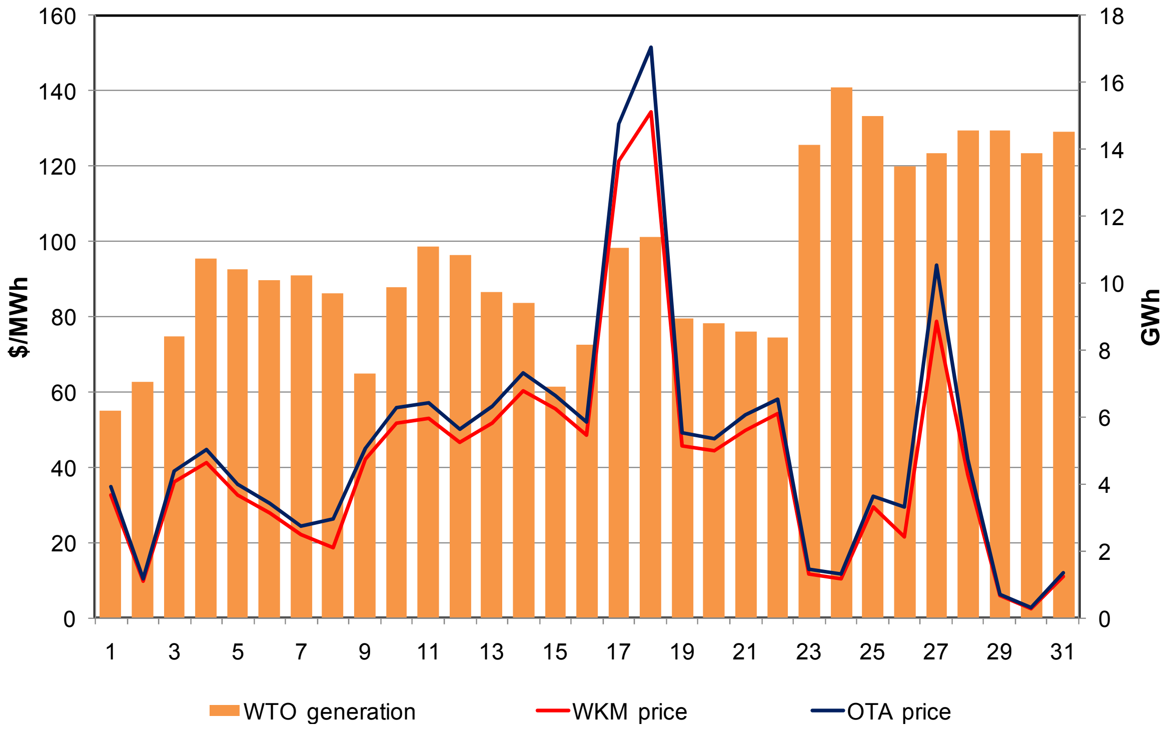
7 See http://www.ea.govt.nz/industry/monitoring/reports-publications/.

3.3 These are the conditions, as outlined above, that give rise to the need for the SO to open the split at Kinleith and actively manage the post contingent loading issue on the 220 kV HAM-WKM circuit.

3.4 On 23 January, beginning at 11:13 hours, the SO began constraining on plant at Huntly. This situation continued off and on for the next several days. The spike in the average daily price on 27 January, evident in Figure 3, was due to the North and South Island prices separating for several periods because of issues having to do with reserves, and is not germane to the constrained-on situation being discussed here. It was the result of a very high price for just two trading periods dragging up the daily average price by about $60/MWh.

Figure 3 Waikato hydro generation and average daily prices

January 2011



Source: Electricity Authority

Note: WTO denotes Waikato hydro, WKM denotes Whakamaru and OTA denotes Otahuhu.

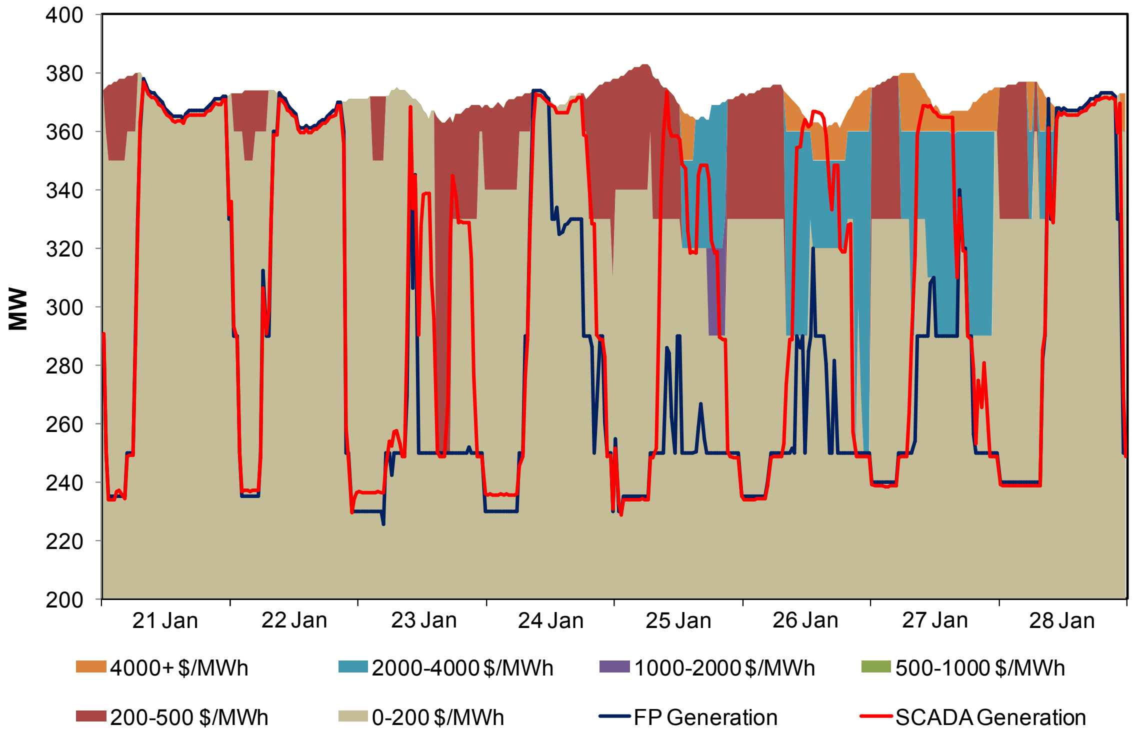
Unscheduled generation and constrained-on costs

3.5 During the week of 23-27 January, the SO frequently instructed units in the upper North Island, particularly Huntly and to a lesser degree Southdown, to dispatch additional unscheduled generation in order to maintain system security.

3.6 Figure 4, Figure 5 and Figure 6 illustrate the degree of unscheduled generation that was dispatched at the Huntly units – HLY5, HLY1-4, and HLY6, respectively. The solid blue line denotes the scheduled quantity from the final pricing process and the red line denotes the actual amount generated according to SCADA data. The difference between the red and blue lines in the following three figures approximately represents the constrained-on amount.

Figure 4 HLY5 offer stack and constrained-on generation

21-28 January 2011



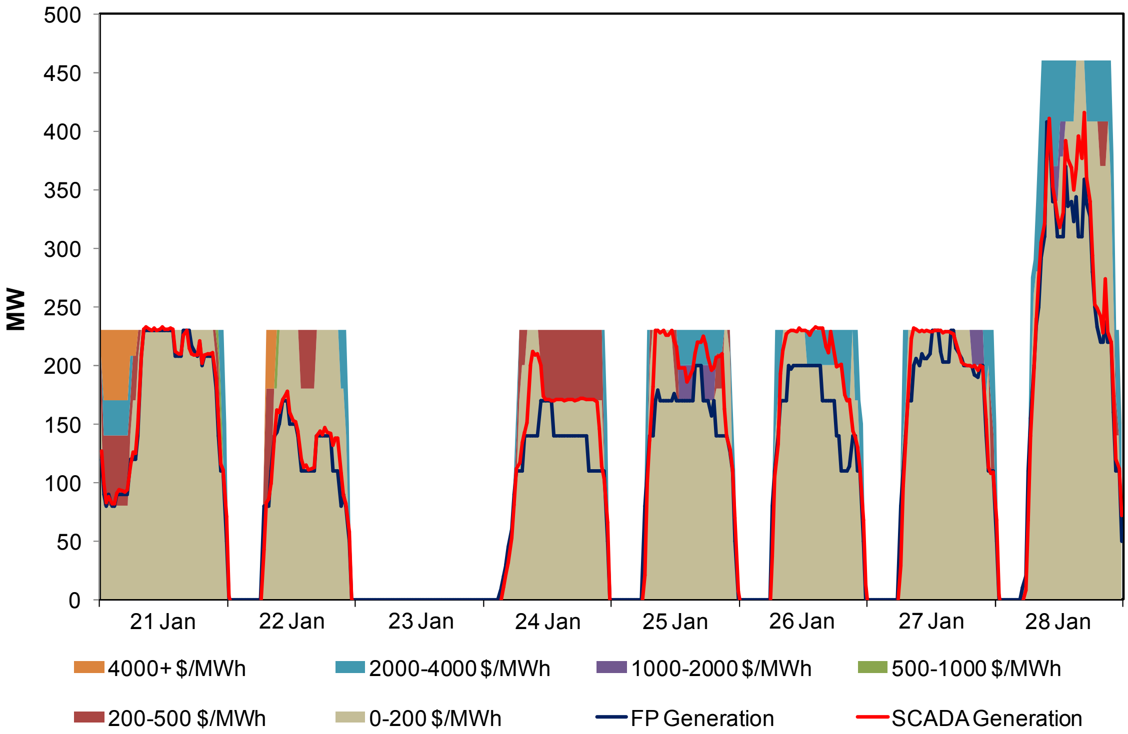
Source: Electricity Authority

Note: FP Generation denotes the amount scheduled by the final pricing SPD schedule.

3.7 The days and periods where significant constrained-on generation occurred are evident in the figures; the red line is some 100-120 MW above the blue line at HLY5 for considerable periods during 25-27 January (Figure 4). The amount of constrained-on generation from one or other of the HLY1-4 units is much less than at HLY5 but is nonetheless significant (Figure 5).

Figure 5 HLY1-4 offer stack and constrained-on generation

21-28 January 2011



Source: Electricity Authority

Note: FP Generation denotes the amount scheduled by the final pricing SPD schedule.

3.8 Figure 6 shows that unit 6 at Huntly was dispatched as scheduled on 21 January when it was offered in at $0.01/MWh (i.e. 1 cent). In the following seven days, HLY6 was either not offered at all or its entire capacity was offered at over $4000/MWh. It was constrained-on for several periods on 26 January and again on 27 January.

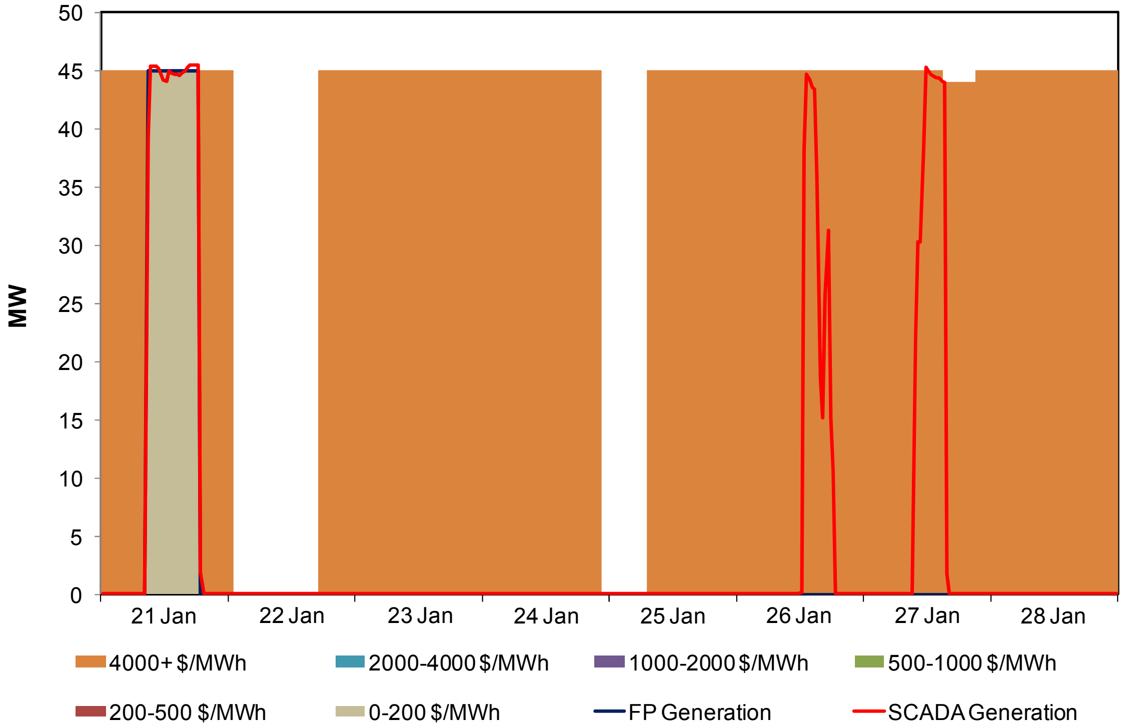
3.9 As can be seen in Figure 4, HLY5 was constrained-on during 23-24 January when the offer price was in the less than $200/MWh band. But on 25 January, Genesis increased its offers for HLY5 effective from trading period 26, i.e. 12:30pm. The constrained-on quantity went from being priced at $400/MWh in TP25 to $4000/MWh in TP26. HLY2 was similarly constrained-on at high prices for periods during 26 and 27 January. This had a dramatic effect on the cost of constrained-on generation. Table 1 shows that constrained-on costs incurred at Huntly alone were over $2.6 million per day on 26 and 27 January 2011.

3.10 Appendix B shows how offers changed at the HLY5 and HLY2 units by trading period during 24-27 January. It is apparent from observing the final offer prices why constrained-on payments increased substantially when the Huntly units were constrained-on.

3.11 Figure 7 compares constrained-on costs for January 2011 with the previous 12 months.

3.12 In addition to plant delivering energy, reserve plant may also be constrained-on. Table 2 lists the costs associated with constraining on reserve plant for January 2011. In some of the periods for which HLY5 was constrained-on, HLY5 was setting the risk. This then required more reserve

Figure 6 HLY6 offer stack and constrained-on generation
21-28 January 2011



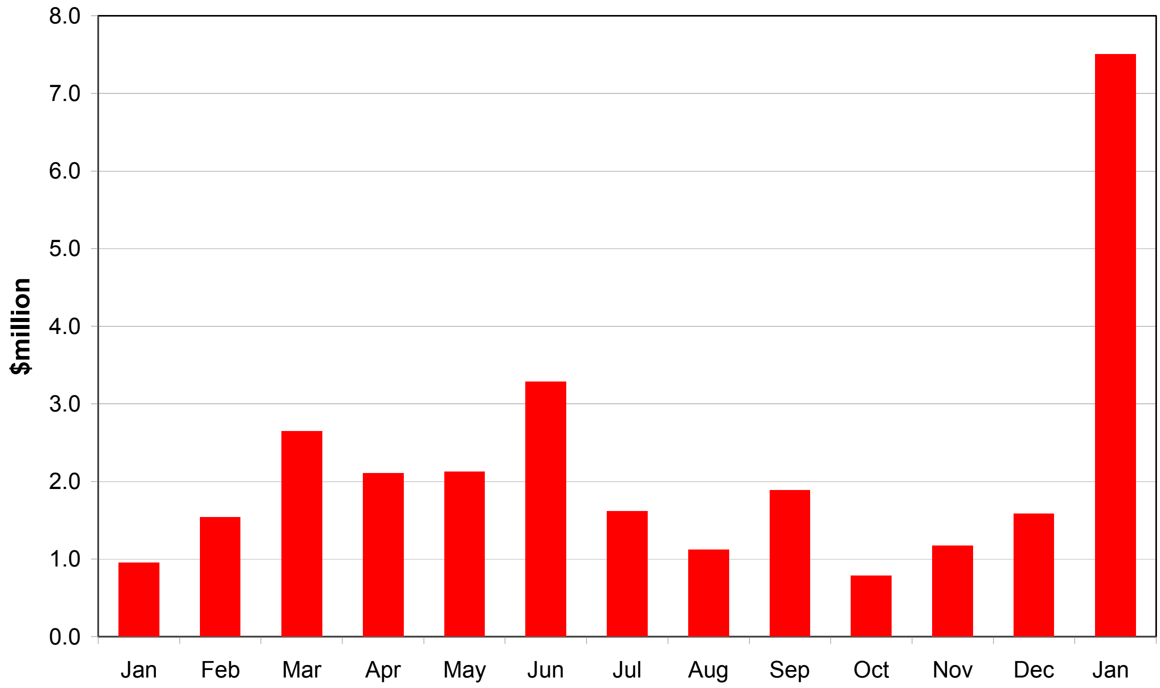
Source: Electricity Authority
Note: FP Generation denotes the amount scheduled by the final pricing SPD schedule

Table 1 Energy constrained-on costs, January 2011
Dollars

	Southdown	Huntly	Other	*Total*
23 Jan	44,601	35,534	21,897	*102,031*
24 Jan	64,672	40,718	5,082	*110,472*
25 Jan	116,580	605,998	23,983	*746,560*
26 Jan	140,136	2,654,144	3,813	*2,798,094*
27 Jan	100,372	2,671,036	36,567	*2,807,975*
All other days	1,037	94,607	844,868	*940,512*
Total	*467,397*	*6,102,036*	*936,211*	*7,505,644*

Source: https://www.electricitywits.co.nz/comit/web_main_pages.home cover to be procured, the cost for which is not reflected in final pricing. As a consequence, some reserve cover is cleared in real time at a price higher than in final pricing, requiring associated constrained-on payments.

Figure 7 Monthly constrained-on costs, January 2010 – January 2011



Source: Electricity Authority

Table 2 Reserve constrained-on costs, January 2011

	Dollars
23 Jan	99.6
24 Jan	3,135.5
25 Jan	291.5
26 Jan	2,263.0
27 Jan	19,151.5
All other days	53,461.5
Total	*78,402.6*

Source: https://www.electricitywits.co.nz/comit/web_main_pages.home

3.13 Constrained-on payments related to reserves are allocated in accordance with the normal methodology for collecting reserve costs, i.e. to the HVDC link and generators with injection above 30 MWh in each trading period.

4 Discussion

4.1 Constrained-on payments for January 2011 were higher than usual due to extensive use of constrained-on arrangements during 23-27 January 2011 and because the constrained-on plant had been offered at high prices.

4.2 The SO was able to devise, test and implement an outage constraint in SPD that alleviated the need to further constrain on generation in the upper North Island when the Kinleith split was in use and the Arapuni runback enabled, and therefore reduced additional constrained-on costs.[8] Following identification of the need for the outage constraint on 23 January 2011, it was 28 January before testing and implementation was able to be completed.

4.3 The SO reports to the Market Administrator, issued just after 7:00am each day, provide a (trading) period-by-period explanation of all discretionary action taken by the SO and the reason for the action.[9] However, it arrives after-the-fact, does not provide any indication of the financial cost associated with the discretionary action, and, in any event, is only made available to the Market Administrator. The absence of real-time awareness by participants of the SO's actions and their consequential costs means that participants have no effective means of managing the uncapped risk they face.

4.4 While it would be desirable to keep the market better informed during periods when constrained-on generation is necessary, it would also be advantageous if the SO had more options at its disposal when faced with situations like that encountered in late January 2011. The ability of load to respond more easily and effectively would be one such option.

4.5 The Authority is currently developing a dispatchable demand regime, which, if introduced, would provide spot market purchasers with the opportunity to be treated in the dispatch process in the same manner as generation. In particular, dispatched-off demand would be paid for their sacrifice in circumstances similar to that occurring for constrained-on generation. Besides offering the potential to provide the SO with additional options to manage grid security, a dispatchable demand regime would also, importantly, provide increased competitive pressure on the offer prices of generators.

4.6 On 2 March 2011, Genesis provided a letter to the Authority with an explanation of why the HLY2 and HLY5 offers were revised upwards on 24 and 25 January 2011, resulting in the constrained-on costs being higher than they otherwise would have been. Genesis explained that its offer revisions were warranted due to fuel management difficulties arising from contractual and operational issues; a desire to limit losses in the reserves market, as HLY5 was the North Island risk setter at the time; and commercial considerations.

4.7 Genesis' exposure to constraining on of the risk setter is limited to its share of the actual constrained-on costs and volume for reserves. As an upper bound, Table 2 shows that Genesis'

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8 A runback is a control procedure to automatically throttle back generation when a set of predetermined conditions arise.

9 See, for example, the SO report to the Market Administrator for the 24-hour period ended 07:00, 26 January 2011 at http://www.ea.govt.nz/industry/monitoring/reports-publications/.

maximum exposure was less than $20,000 on 27 January, and only if it was the sole generator injecting more than 30 MWh in each trading period on that day.

4.8 This is an after-the-fact estimate of the upper bound to the risk faced by Genesis. Given that the maximum offer price for both reserve classes was $1,000/MWh, the actual maximum constrained-on reserve cost for 1 MW of constrained-on energy is about $2,000/MWh; much less than Genesis' $4,000/MWh offer price for energy. This constrained-on reserve cost is allocated not only to Genesis but to other generators and the HVDC link in accordance with the Code.

4.9 All operators of thermal plant need to manage their fuel supply arrangements, including minimising the costs associated with contractual and operational obligations, regardless of the reason the plant was dispatched. Such costs of generation should therefore be reflected in the plant offer price at all times. An alternative explanation of the offer price increases on 24 and 25 January is that Genesis was in a position to profitably increase offer prices without the discipline of a competitive market, as the SO had few other feasible options for increasing generation in the upper North Island.

Sensitivity analysis

4.10 Table 3, Figure 8 and Figure 9 show the results of two simulated pricing scenarios derived using vSPD for the three days in question in January.[10] The simulations were undertaken over trading periods 15-42 rather than the entire forty-eight periods in each day because this interval represents the daytime periods when most of the constraining-on occurred. The intent of this sensitivity analysis is to demonstrate the inefficiency in pricing associated with heavy usage of constrained-on generation.

4.11 The upper panel of Table 3 and the blue bars in Figure 8 show the nationwide load-weighted average daily price paid by spot market purchasers, as priced according to actual final prices ($41.53, $38.36 and $107.74 per MWh on 25, 26 and 27 January, respectively). The red bars augment this price with the constrained-on payments to Huntly and Southdown during TP15-TP42 on 25-27 January 2011 ($52.09, $79.77 and $148.38 per MWh on 25, 26 and 27 January, respectively). Hence, the red bars show the total implied load-weighted average price for energy paid by spot market purchasers.

4.12 The green bars in Figure 8 depict the first of the two counterfactual pricing simulations and show the nationwide load-weighted average daily price paid by spot market purchasers had the outage constraint been implemented in the SPD final pricing case on 25-27 January ($74.34, $64.63 and $266.48 per MWh on 25, 26 and 27 January, respectively). The SO actually implemented the constraint on 28 January.

4.13 Finally, the purple bars in Figure 8 show the nationwide load-weighted average daily price paid by spot market purchasers had the outage constraint been modelled <u>and</u> if Genesis had kept its offer at $400/MWh instead of increasing it to $4,000/MWh ($62.54, $58.41 and $125.08 per MWh on 25, 26 and 27 January, respectively).[11]

4.14 Figure 9 and the lower panel of Table 3 present a different view of the same simulation results. Now the load-weighted average price is calculated on a regional basis over all three days in question. The three sets of results depicted are for the upper North Island (i.e. the area electrically north of Hamilton), the remainder of New Zealand, and, for the sake of comparison, all

[10] The vSPD model is the Authority's replica of SPD, the market clearing engine.

[11] For the avoidance of any doubt, the Authority is not assigning any particular meaning to the figure of $400/MWh. It has been selected for no other reason than it happened to be the value Genesis offered at prior to increasing its offer to $4,000/MWh.

of New Zealand. The all of New Zealand results are just the load-weighted average of the upper North Island and the rest of New Zealand.

Table 3 Load-weighted average prices, $/MWh
TP15-TP42, 25-27 January 2011

	25 Jan	26 Jan	27 Jan
Final pricing	41.53	38.36	107.74
Final pricing with constrained-on payments	52.09	79.77	148.38
Simulation 1	74.34	64.63	266.48
Simulation 2	62.54	58.41	125.08
	Upper North Island	**Rest of NZ**	**All New Zealand**
Final pricing	85.47	47.83	62.66
Final pricing with constrained-on payments	116.27	78.63	93.46
Simulation 1	269.94	48.09	135.47
Simulation 2	154.09	35.35	82.12

Source: Electricity Authority

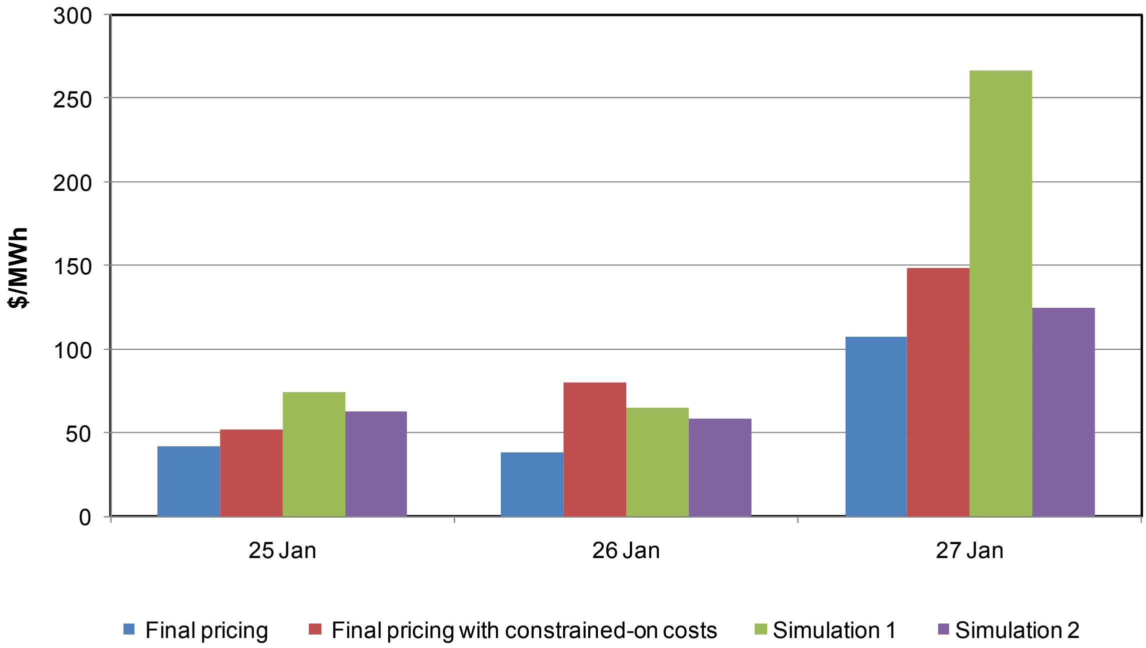
Notes:
1. Simulation 1 assumes the SPD outage constraint introduced by the SO on 28 January 2011 was in use on 25-27 January.
2. Simulation 2 assumes the Huntly offers for trading period 16 on 25 January apply for all trading periods during 25-27 January and the SPD outage constraint introduced by the SO on 28 January 2011 was in use on 25-27 January 2011.

4.15 These results suggest that, on average, spot market purchasers would have paid a higher price if the outage constraint had been in use during 25-27 January 2011 and if the offers by Genesis were assumed to be as actually occurred during 25-27 January 2011 compared with the case where the SO was left to exercise discretion, i.e. compare the green bars with the red in Figure 8. The higher price paid by spot market purchasers arises because the high prices paid to Genesis in this simulation would have increased prices paid for a significant share of the total load.

4.16 However, Figure 9 demonstrates the inefficiency of prices in the case where the SO has the discretion to make heavy use of constrained-on payments. Spot market purchasers in the upper North Island, the area impacted by the underlying grid security issues, pay a much higher price for energy under the market-based arrangements than do spot market purchasers in the rest of New Zealand, i.e. compare the green with the red bars in Figure 9. Note that the green bar is higher than the red for the “All New Zealand” result in Figure 9 because the high price in the upper North Island is heavily-weighted due to the large load in the region.

Figure 8 Load-weighted average daily price, 25-27 January 2011

All of New Zealand, TP15-TP42



Source: Electricity Authority

Notes:
1. Simulation 1 assumes the SPD outage constraint introduced by the SO on 28 January 2011 was in use on 25-27 January.
2. Simulation 2 assumes the Huntly offers for trading period 16 on 25 January apply for all trading periods during 25-27 January <u>and</u> the SPD outage constraint introduced by the SO on 28 January 2011 was in use on 25-27 January 2011.

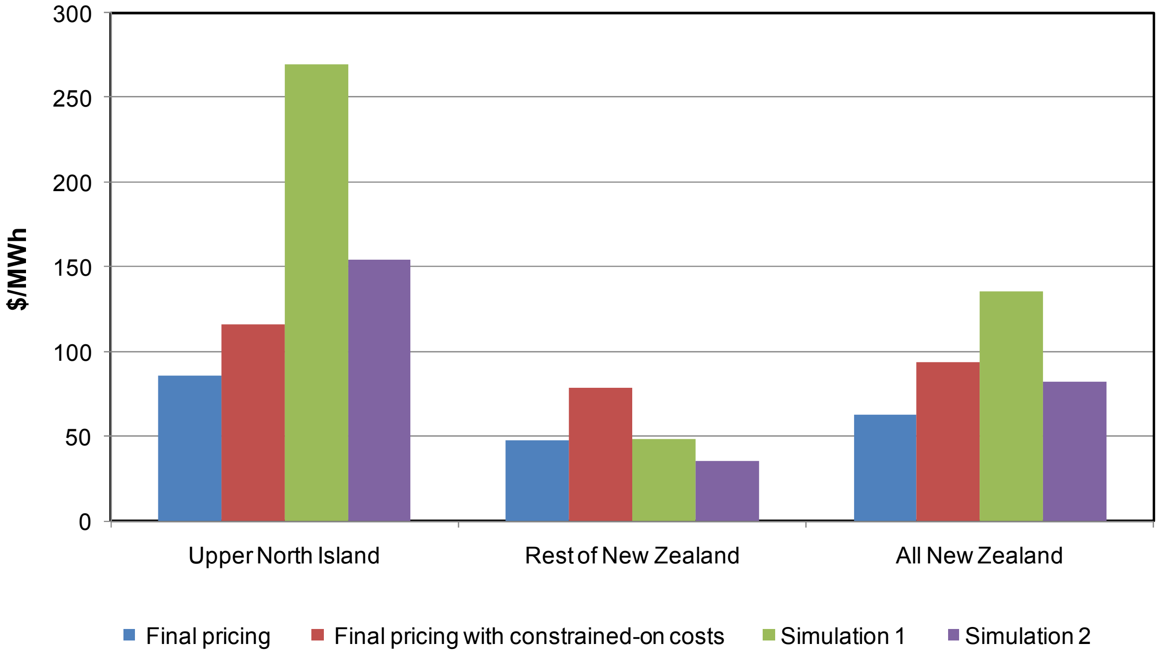
4.17 In other words, off-take customers in the upper North Island pay proportionately more for energy than the rest of New Zealand, reflecting the cost of delivery to that region and, in particular, the cost associated with managing grid security in the region.

4.18 Assuming Genesis did not change its offer prices, i.e. the purple bars, the simulations suggest that the price paid by spot market purchasers is lower when priced through the market clearing process (i.e. SPD with appropriate outage constraints) and grid security costs are more efficiently allocated than is the case when the SO constrains out-of-merit-order plant to run.

4.19 In reality, had the SPD outage constraint been in use <u>and</u> if Genesis then offered exactly as they did without the constraint, it is likely that the resulting prices may have been close to $4,000/MWh in the upper North Island. This may have induced lower-cost sources of energy (and demand response) to enter the market, as participants would have seen all of this playing out in the pre-dispatch schedules.

4.20 A deficiency with this analysis is that the counterfactual vSPD solutions are underpinned by an assumption that other offers do not change. It would be expected that shortly after price separation occurred participant price and quantity offers would be adjusted to manage exposure to those prices. Thus it is entirely possible that load-weighted average prices paid by spot market purchasers would be less than is suggested by simulation 2.

Figure 9 Load-weighted average price paid by spot market purchasers
TP15-TP42, 25-27 January 2011



Source: Electricity Authority

Notes:
1. Simulation 1 assumes the SPD outage constraint introduced by the SO on 28 January 2011 was in use on 25-27 January.
2. Simulation 2 assumes the Huntly offers for trading period 16 on 25 January apply for all trading periods during 25-27 January and the SPD outage constraint introduced by the SO on 28 January 2011 was in use on 25-27 January 2011.

5 Conclusions and possible next steps

5.1 Requiring unscheduled plant to be dispatched to any significant degree is undesirable because it takes place outside of market mechanisms. Participants are left in a position where they are unable to make efficient, cost-reflective decisions. They are also left exposed to an unknown (at the time it is incurred) and uncapped financial liability; a risk they have very limited means of managing.

5.2 Participants constrained-on for grid security reasons may find themselves in a position where they can increase their offer prices knowing they face almost no competition for the SO's attention.

5.3 The Authority considers that it would be desirable if the market was better and more quickly informed during periods when the SO needs to dispatch unscheduled plant. The need to dispatch unscheduled plant reflects an inability of the existing market mechanisms to provide the appropriate signals to ensure that system security requirements are satisfied.

5.4 On 28 February 2011, MEUG alleged that the actions taken by the SO in constraining on generation plant during 23-27 January 2011 constituted a breach of the Code. The Authority's Compliance team is undertaking a fact-finding exercise and expect to report their findings to the Authority's Compliance Committee in the near future.

Possible next steps

5.5 The preceding discussion suggests a framework within which possible next steps that amend the Code to enhance competitive pressures can be envisaged.

5.6 The current arrangements provide no opportunity for parties other than the constrained-on generator to offer assistance in resolving the underlying grid security problem that gives rise to the constrained-on generation in the first place. Hence, a situation is created with very weak, if any, competitive pressure on the constrained-on generator.

5.7 Purchasers in the spot market, and other generators, don't know in real-time, or even ahead of real-time, the structure of the offers from the constrained-on generator. This makes it very difficult, if not impossible, for spot market purchasers to assess the financial risk to which they may be exposed, and to take any action to mitigate such risks.

5.8 Possible next steps include consideration of potential Code changes suggested by:

a) Examining how better information can be provided to the market in advance of and during periods of unscheduled plant dispatch. For example, further consideration could be given to whether and how the market could be more quickly informed of the offer prices of plant that are constrained-on;

b) Examining whether there are market-based solutions to increasing the options available to the SO during constrained-on periods. For example, consideration could be given to whether it is feasible and cost-effective to establish a constrained-on market analogous to the instantaneous reserves market; and

c) Examining the SO's ability to use its automatic constraint builder (SFT) to help reflect the cost of managing system security in pre-dispatch schedules and ultimately final nodal prices.

5.9 The Authority will consider in its next work programme review how best to further progress the above possibilities.

Appendix A Timeline of key events[12]

Date	Event
23 Jan 2011	SO uses its discretion to constrain on HLY5 from 11:13-14:30 and again from 16:45-21:50, and SWN5 from 14:30-21:00. HLY 5 offered and cleared at $400/MWh. SO constrained it on at a higher load than it was offered at. SO reports they advised respective generators that duration of use of discretion was unknown at this stage.
24 Jan 2011	SO again exercises discretion to constrain on SWN5, HLY2 or HLY5 between 08:04 and approximately 21:00. At approximately 13:30, Genesis advised SO of their concern that discretion on the risk setter was changing the North Island reserve price. Also expressed concern at lack of market information. SO reviews its actions and advises Genesis that it (i.e. SO) believes its actions to be correct and consistent with the dispatch objective. At 16:00, Genesis increases energy offer prices for HLY2 and HLY5. Genesis also advises SO that HLY2 would be taken offline once Rangipo was returned to service (expected to be 26 Jan 2011).
25 Jan 2011	Rangipo returned to service. SO advise Genesis that a resolution to the grid security problem is not imminent and discretion could be required for much of the day. Generation constrained-on between 07:35 and 19:50 – HLY2, HLY5 and SWN5. Genesis increases energy offer prices at 12:30 – to $3,000/MWh for HLY2 and $4,000/MWh for HLY5. Five periods later they are reduced but remain very high for much of the rest of the day. SO notifies Authority that HLY5 constrained-on at $2000/MWh.
26 Jan 2011	SO again exercising discretion to constrain on HLY2, HLY5, and HLY6 between 07:23 and 20:28.
27 Jan 2011	SO again exercising discretion to constrain on SWN5, HLY2, HLY5, and HLY6 between 07:15 and 15:29. At 15:03, the SO issued a CAN announcing the new outage constraint to be used in SPD when the Kinleith splits are required (KIN_TRK_SPLIT&ARI_RUNBACK_enabled_S_0_1_temp). The final pricing case files shows the constraint was first was included in TP15 (07:00am) on 28 Jan.
28 Jan 2011	Authority emailed the following questions to Genesis: 1. Are there any operational constraints that cause the high offers to be reflective of avoidable costs of dispatch? 2. Please explain why any such costs became relevant on the 25th but not in the days before?

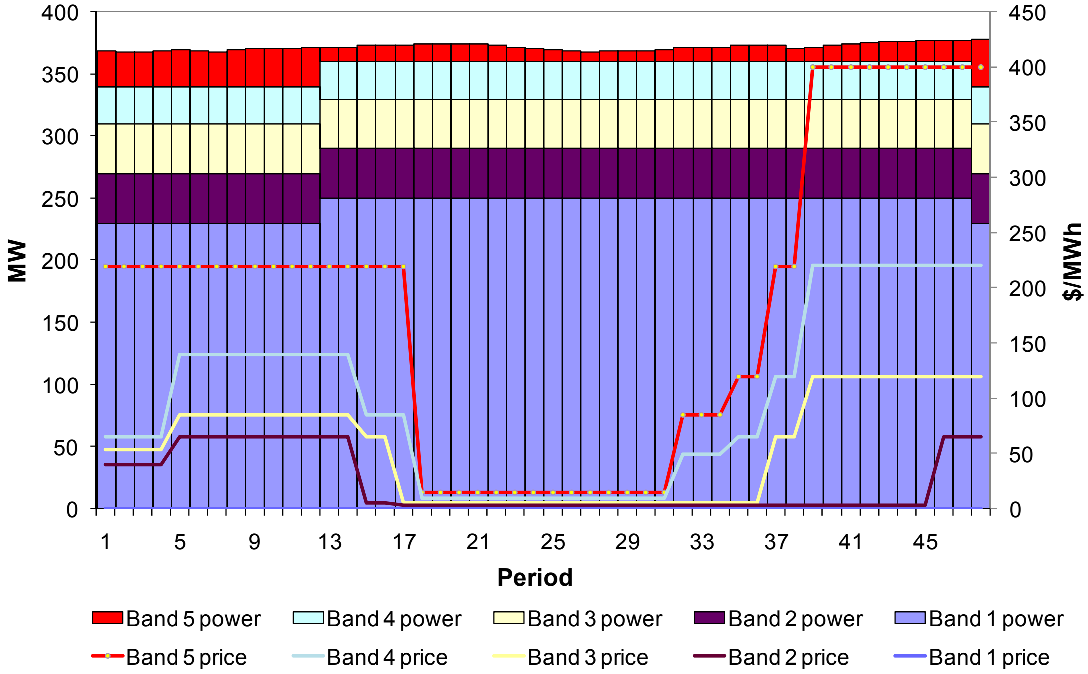
12 Some of the material presented in this appendix is lifted from letters the Authority received from the SO (on 11 and 28 February) and from Genesis on 2 March 2011. For completeness, it is recommended that readers of this report also read those letters.

Date	Event
	3. At what time, and by what means, did Genesis become aware that the plant was likely to become constrained-on for several hours over several days? 4. Did the System Operator give you any advance notification that the plant would need to be constrained-on outside the market dispatch? If so, at what time did this notification occur?
1 Feb 2011	Authority emailed the following questions to the SO: 1. At what time and by what means did the SO notify Genesis that Huntly units would be constrained-on? 2. What notification, if any, was given to Genesis of the duration over which it would be necessary to constrain-on Huntly units? 3. Why was the market schedule, pricing and dispatch engine unable to schedule HLY generation in such a way that transmission constraints could be managed? 4. Has this been an ongoing issue and, if so, what steps has the SO taken (or is taking) to resolve this? 5. Were there any other factors that influenced the SO's decision to constrain-on HLY? 6. Would this issue be resolved with the implementation (in March 2011) of the SO's new automatic constraint builder (SFT)?
11 Feb 2011	SO replies to Authority's questions of 1 Feb – see http://www.ea.govt.nz/industry/monitoring/reports-publications/.
15 Feb 2011	MEUG informs the Authority that their members are unhappy following receipt of invoices for constrained-on payments for January 2011.
22 Feb 2011	Contact writes to the Authority expressing concern at magnitude of constrained-on payments for January 2011 – see http://www.ea.govt.nz/industry/monitoring/reports-publications/.
23 Feb 2011	Authority emailed the following questions to the SO: 1. Why was the SO's existing constraint development process unable to identify the need for a constraint to manage the flows on the 220kV network when Kinleith splits are in place at a much earlier stage, e.g. prior to 23 January 2011? There is some evidence that this network reconfiguration at Kinleith has been used since September 2010. 2. It appears that the SO's new automatic constraint builder (SFT) was operating in parallel during this period. Did SFT identify a constraint to manage the situation that occurred during 23-28 Jan 2011? 3. Will the constraint identification, development, and implementation into the dispatch process occur more quickly following the implementation of SFT? 4. A review of the SO's grid emergency notices suggests that the market was informed that a grid reconfiguration was to be implemented in order to manage transmission constraints. When and how was the market notified that discretionary constraining on of generation in the Upper North Island was also being used to manage the transmission constraints during the period 23-28 January?
28 Feb 2011	Authority announces that it is examining this event – see http://www.ea.govt.nz/about-us/news-events/market-briefs-media-

Date	Event
	releases/28Feb11/.
	SO replies to Authority's questions of 23 Feb – see http://www.ea.govt.nz/industry/monitoring/reports-publications/.
	MEUG alleges the SO to be in breach of part 8, clause 8.8(3) of the Code.
2 Mar 2011	Genesis replies to Authority's questions of 28 Jan – see http://www.ea.govt.nz/industry/monitoring/reports-publications/.
18 Mar 2011	MRP writes to the Authority expressing concern at magnitude of constrained-on payments for January 2011 – see http://www.ea.govt.nz/industry/monitoring/reports-publications/.

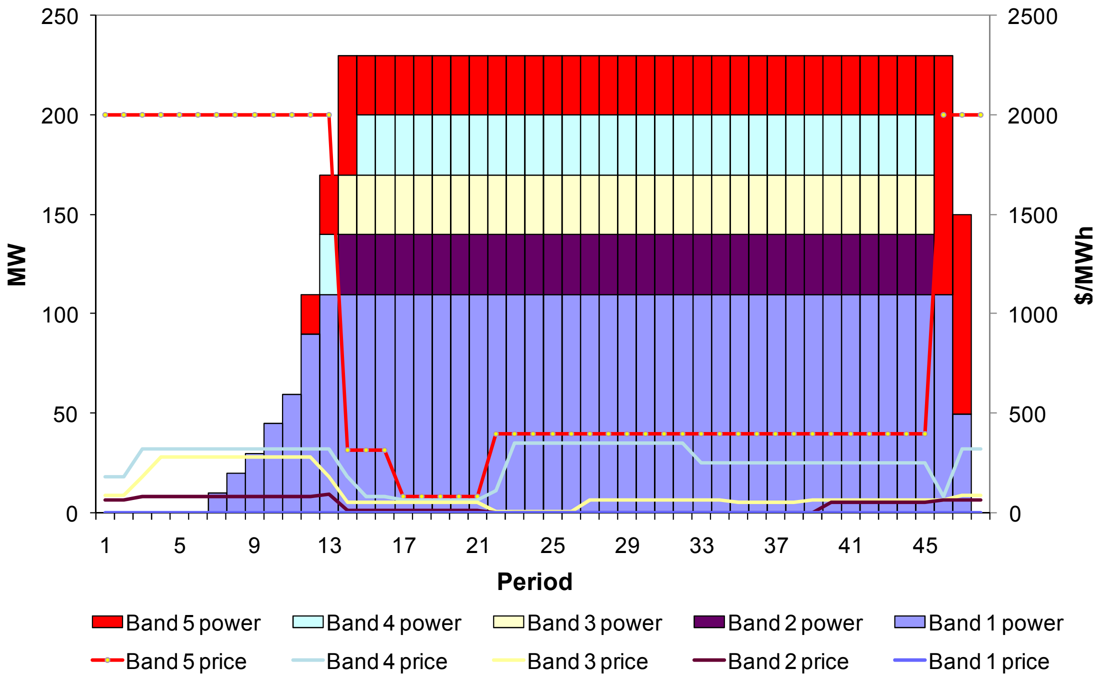
Appendix B Selected Huntly offer structures, 24-27 January 2011

Figure 10 HLY5 offer structure, 24 January



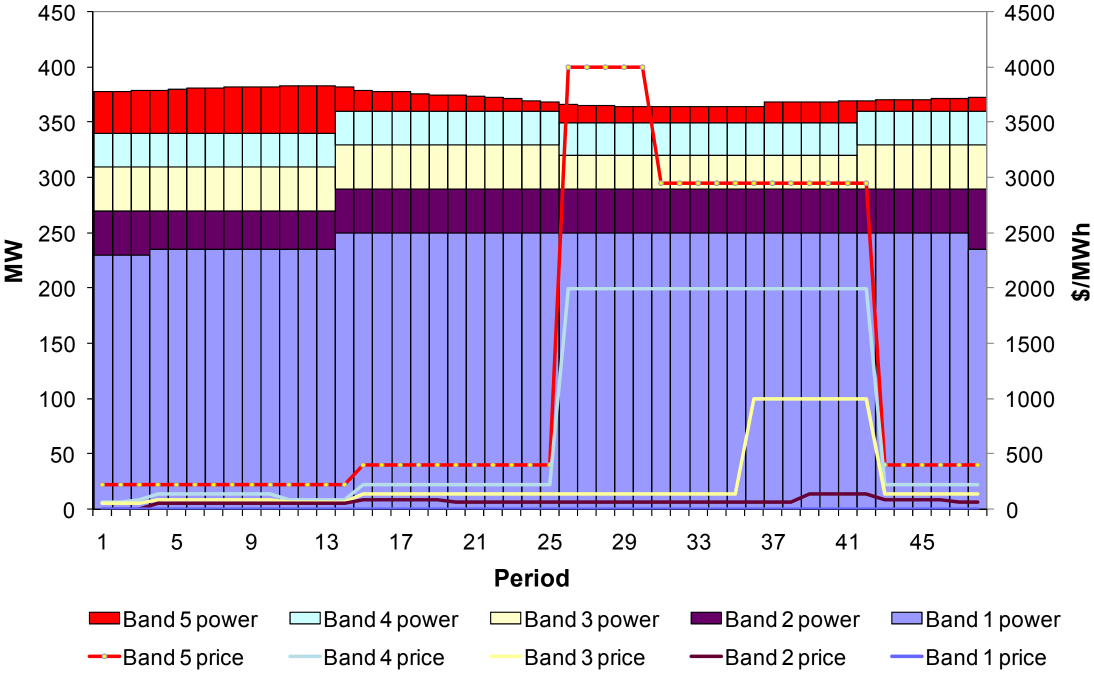
Source: Electricity Authority

Figure 11 HLY2 offer structure, 24 January



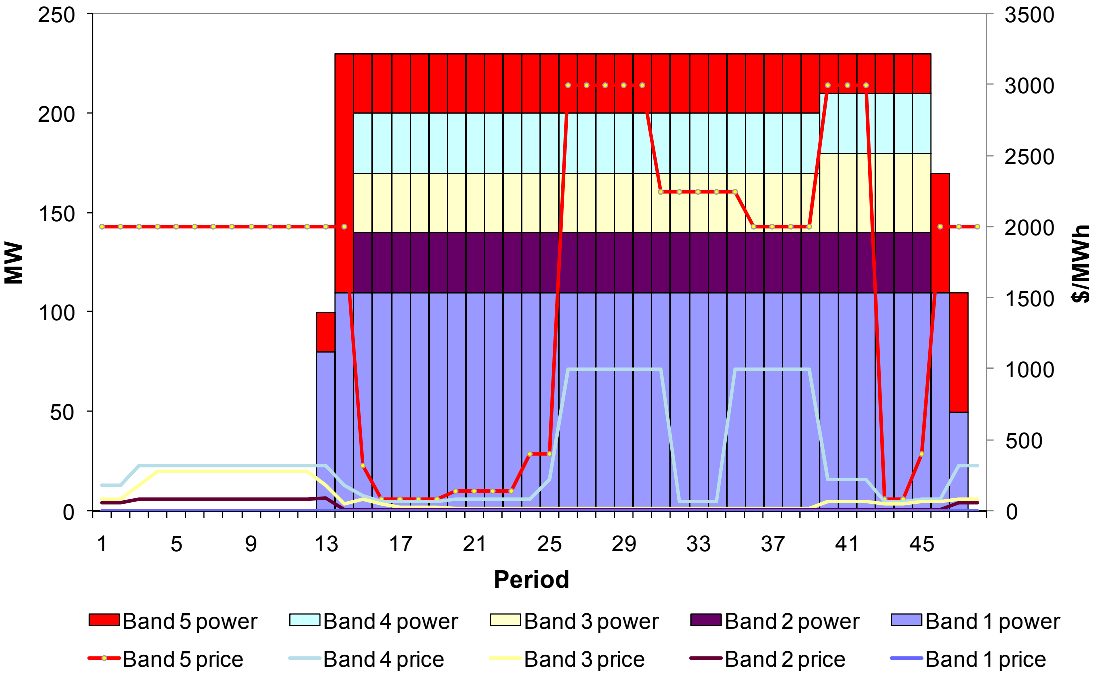
Source: Electricity Authority

Figure 12 HLY5 offer structure, 25 January



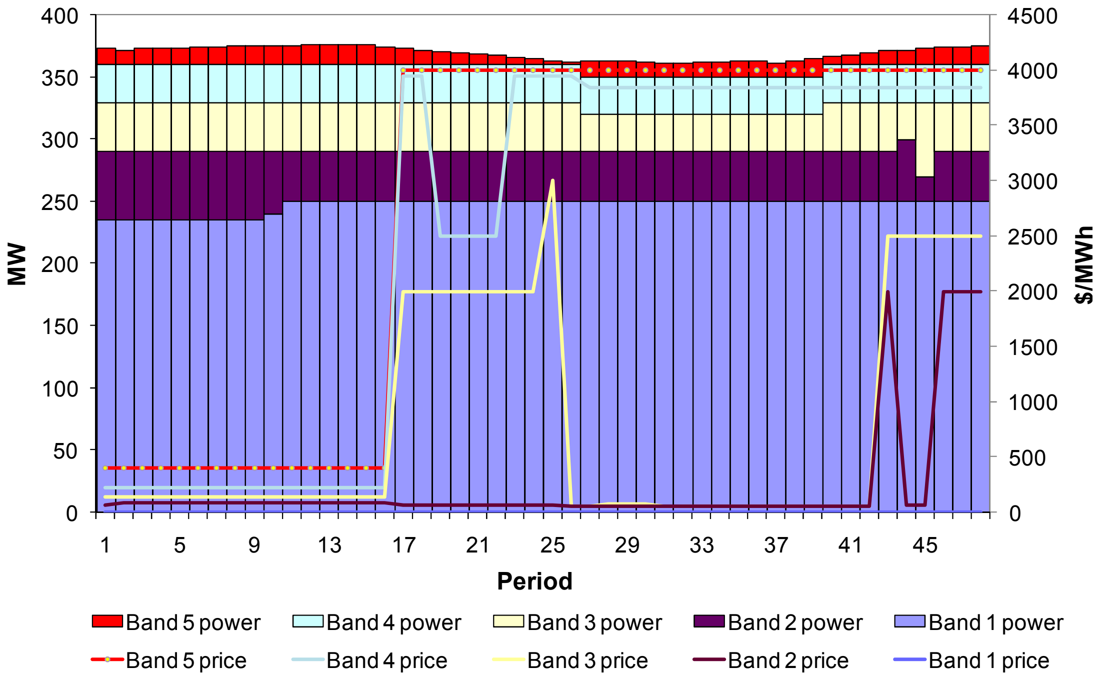
Source: Electricity Authority

Figure 13 HLY2 offer structure, 25 January



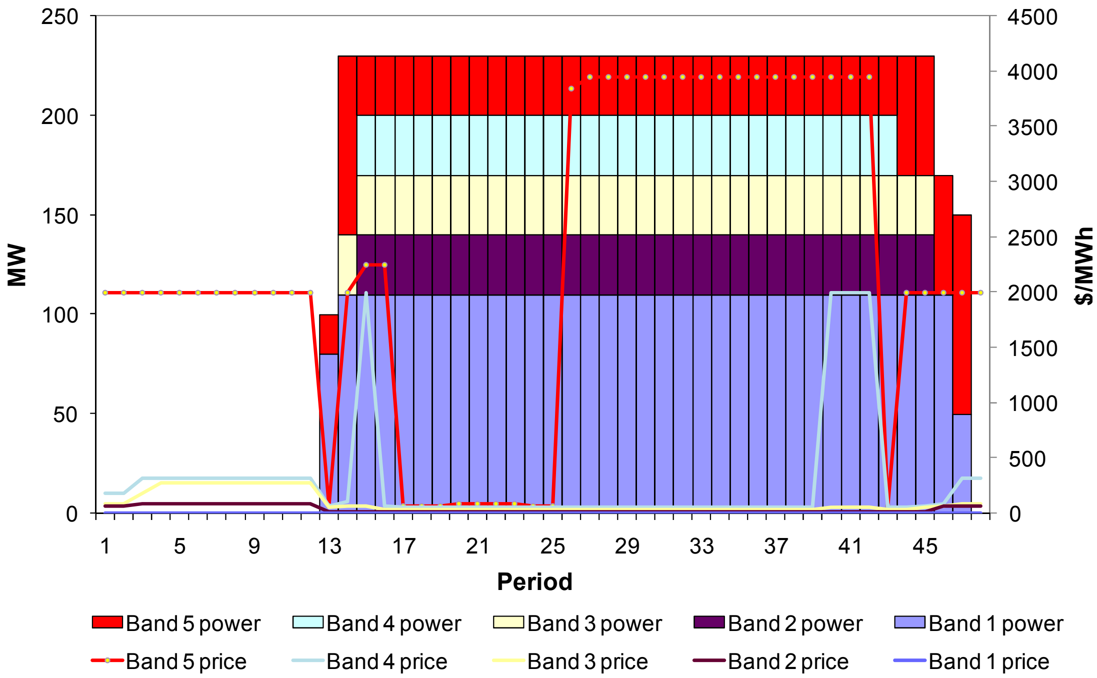
Source: Electricity Authority

Figure 14 HLY5 offer structure, 26 January



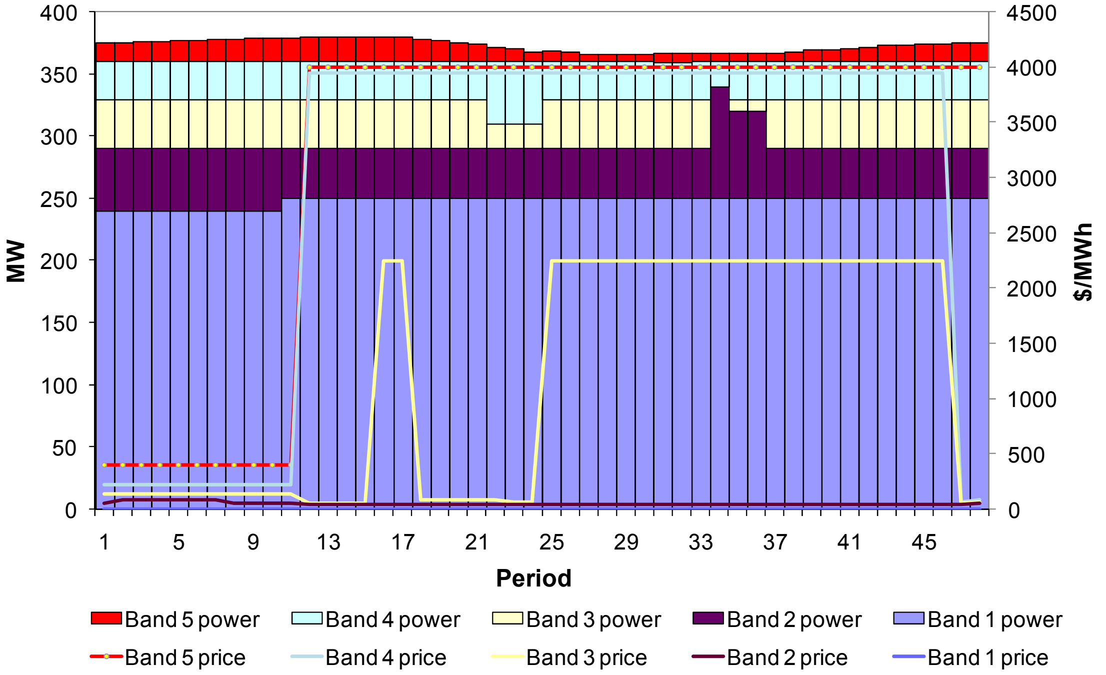
Source: Electricity Authority

Figure 15 HLY2 offer structure, 26 January



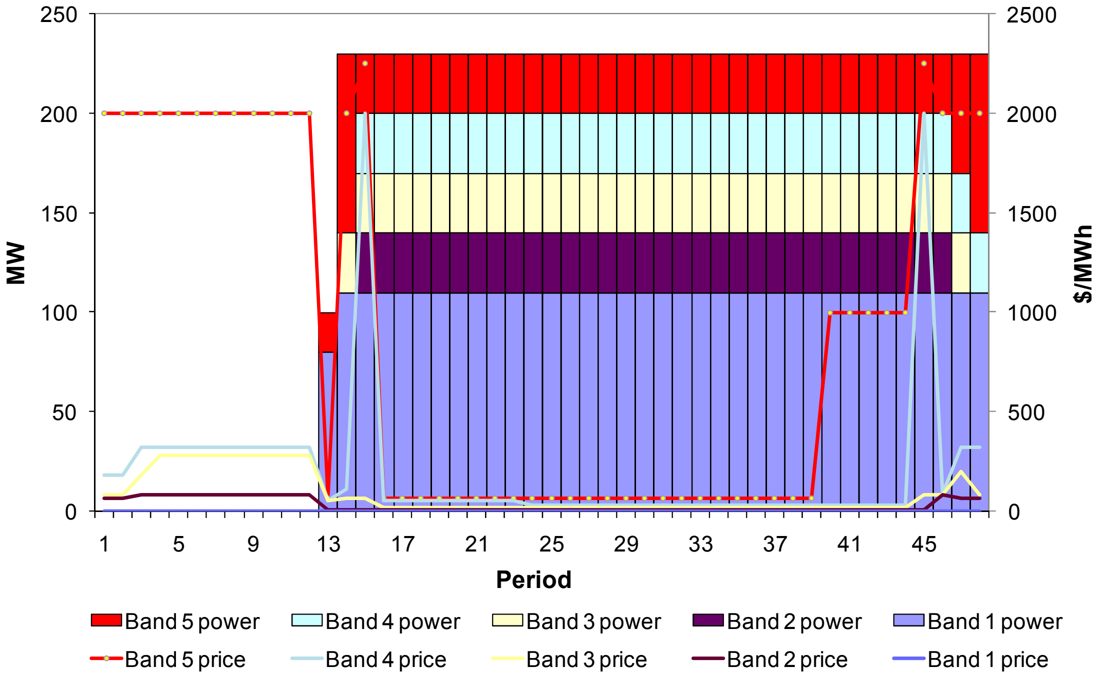
Source: Electricity Authority

Figure 16 HLY5 offer structure, 27 January



Source: Electricity Authority

Figure 17 HLY2 offer structure, 27 January



Source: Electricity Authority

Glossary of abbreviations and terms

ARI-PAK	Arapuni-Pakuranga
Authority	Electricity Authority
CAN	Customer Advice Notice
Code	Electricity Industry Participation Code 2010 See http://www.ea.govt.nz/act-code-regs/code-regs/the-code/.
Constrained-on	A constrained-on situation is as defined in clause 13.202 of the Code. Constrained-on compensation means the amounts payable to a generator or ancillary service agent and the amounts payable by the SO or a purchaser or the HVDC owner in accordance with clauses 13.202 to 13.212 of the Code.
Contact	Contact Energy Limited
Genesis	Genesis Power Limited
GWh	Gigawatt hour
HAM-WKM	Hamilton-Whakamaru
HLY1-4	Huntly units 1, 2, 3 and 4 (sometimes collectively referred to as HLY0)
HLY5	Huntly unit 5 (also known as e3p)
HLY6	Huntly unit 6 (also known as P40)
HVDC	High Voltage Direct Current
KIN-TRK	Kinleith-Tarukenga
MEUG	Major Electricity Users' Group
MRP	Mighty River Power Limited
MW	Megawatt
MWh	Megawatt hour
OHW-WKM	Ohinewai-Whakamaru
OTC	Otahuhu B generating plant
SCADA	Supervisory Control and Data Acquisition
SFT	Simultaneous Feasibility Test
SO	System Operator
SPD	Scheduling, Pricing and Dispatch
SWN5	Southdown unit 5
TP	Trading Period
vSPD	Vectorised Scheduling, Pricing and Dispatch